Minutes from Federal Gas Rule Workshop
Houston, Texas
April 29, 2003

A Federal Register Notice dated Thursday, April 10, 2003, announced that the Minerals Management Service (MMS) would hold four public workshops to discuss specific issues regarding the existing Federal gas royalty valuation regulations at 30 CFR Part 206 for natural gas produced from Federal leases.

Seventy five participants attended the Houston workshop representing 28 Companies, 4 State Agencies, and 1 Law Firm.

<u>Opening Statements</u>
Lucy Querques Denett introduced the panel members and welcomed the participants. This is the 3rd of 4 workshops to be held around the country. Minutes for the meeting will be out on MMS' website. You may also send written comments to MMS.

The purpose of the current Federal gas rule is to ensure that the public receives a fair return on Federal resources. MMS believes the rule accomplishes this goal. However, we continually evaluate the effectiveness and efficiency of our rules. The existing rule is now 15 years old. With the changes in the natural gas market, our experience with the 2000 Indian gas rule, and 5 years of taking gas in kind, we are reevaluating the rule and asking for public input from our constituents. We are seeking simplicity, but not at the cost of a fair return.

We seek comments on the following issues:

- Should we simplify the current benchmark system for non-arm's-length sales? Should we allow lessees who sell production to an affiliate a 2-year option (similar to the oil rule) to base royalty value on either a published index for natural gas or their affiliate's arm's-length resale?
- Should we consider using NYMEX prices at Henry Hub in place of, or in addition to, published index prices?
- How should we adjust index prices for location differences?
- Are there other pipeline charges since MMS' 1998 amendment to the gas transportation allowance regulations for which MMS should provide clarification on whether they are allowable?
- Should MMS adjust the allowable rate of return for calculating non-arm's-length transportation allowances?
- Should MMS allow lessees to apply an index price to wellhead volumes to eliminate the requirement of tracing processed gas to remove liquids?
- Should MMS clarify valuation under joint operating agreements (JOA)?

Industry Comment:

- The Royalty Strategy Task Force, which includes most major industry organizations such as API, IPAA, IPAMS, etc, plans to offer lots of comments. Our submittal will be unscripted, but will be similar to what we provided for the recent oil rule changes. In some ways oil and gas have a lot in common but they are not exactly the same.

<u>Affiliate sales</u>

Question: Currently, affiliate sales value is determined under the benchmarks, but in no case is less than gross proceeds. How are the current regulations working for affiliates?

Industry Comment:
- Auditors largely ignore the benchmarks and seem to look solely to affiliate sales. The benchmark regulations end up being ignored.

State Comment:
- We see that companies generally resell after selling to their affiliate, and we can look to the resale to determine price. If there is an arm's-length resale, we should look there first.

MMS Comment: At previous workshops, a statement was made that more companies systems' calculate gross proceeds and companies are eliminating their sales to affiliates.

Industry Comments:
- Auditors look through the non-arm's-length sale trying to determine what true gross proceeds are. If gross proceeds weren't part of rules, the auditors wouldn't look downstream. By looking downstream they are required to look through the affiliate's sale.
- Large companies such as ExxonMobil sell non-arm's-length to their refineries and gas plants, would this apply?

MMS Comment: In that situation, benchmarks do apply because there is no affiliate arm's-length resale of the gas. We heard a number of comments from other workshops that the gas marketing industry is in flux, and MMS should be cautious of index.

<u>Use NYMEX in addition to, or instead of, Index (spot) Prices</u>

Question: Should MMS use NYMEX instead of, or in addition to, index?

Industry Comments:
- Our company believes the gas marketing industry is in a major coma. People have been run out of business. We believe the current indexes have melted down and are not reliable. At the FERC hearing, we are suggesting that the government might do 3rd party reporting to eliminate manipulation. A congressional bill currently circulating (HR 6) suggests authorizing FERC to develop a natural gas reporting system. MMS might use the NYMEX based price because it is the only index that is semi-reliable.
- Urge MMS to coordinate with FERC. The Houston Chronicle investigated wash sales. California and Louisiana are moving to NYMEX. MMS might consider doing the same until FERC can publish non-manipulated and reliable prices.

MMS Comment: In other workshops, we heard comments suggesting that starting with NYMEX and using a location differential ends up back to index, so why not start with index?

Industry Comments:
- Any price used would have to include a transportation differential, but NYMEX seems the most reliable. As a large independent, we see index as unreliable. The second largest income to the United States treasury needs to be more reliable.
- NYMEX vs index: There is a timing disconnect with oil. How do you apply NYMEX in contracts versus how Platt's would make trade/location differentials and apply it to their WTI indexes? There is a disconnect between trade journals and reporting for MMS. But, gas index actually replicates better than NYMEX. NYMEX must bridge the local market. Spot prices have actual real time with built in location differentials, you don't see a disconnect. There may not be multiple trades done in remote locations, but trades are based on actual transactions rather than trying to use the mechanism of a single point (NYMEX) verses multiple pipelines.
- Sometimes natural gas and crude are different. The crude index hasn't gone through scandal that the natural gas indexes have. The index system is completely broken down and a great level of distrust exists. There is a deep abiding crisis of confidence at FERC. To go

immediately to index seems to be contrary based on the current situation. Other Federal agencies (FTC, FCC) have criticized indexes, and we've seen admissions of wrong doing, fines, indictments, and newspaper exposé. Using index is not good, not close enough. NYMEX is closer and FERC should make index verifiable, to continue to rely on index does not make sense.

MMS Comment: Are there other choices? Real, actual money sales are still based on index prices. When index evaporated and companies weren't sure what to use as value, suggestions included using NYMEX and basis differentials. MMS studied this for RIK basis differentials but we haven't studied it for onshore in places like Wyoming and New Mexico. We found a huge difference between spot prices and the Henry Hub, 20 cent differential between the Louisiana coast and the Henry hub. It's not obvious that only transportation makes up the differential. How do you get back to the lease? For coalbed methane, there was no relationship to Henry Hub, but if spot prices can be trusted why is there difference between index at Henry Hub and NYMEX at Henry Hub? We see this as an issue. What is the right way to go? If the eventual sale is at a spot price, the value is gross proceeds anyway and it's clear that industry still uses spot price as the easiest method to arrive at a sales price.

Industry Comments

- Lot of companies, including us, aren't opposed to the index system in theory. It's an elegant system, especially for small producers and large consumers. We are supporters of index in theory, but in practice index is broken. Industry is trying to talk to FERC and Congress. Index is embedded everywhere. The goal is an index system that is reliable and verifiable. What do we do until that happens or if it doesn't happen? Everyone is making significant decisions on what to do with index prices, most people are getting and will be paid on index. At some point, index needs to change and MMS must be in the movement for change, but now, shouldn't rely on prices that don't have reality. Going to NYMEX and pulling out transportation differentials is the best of two choices at this time.
- Looking at the market, you cannot use NYMEX, which is based on future sales not on actual sales. Industry still uses index not NYMEX. This is still a huge disconnect between futures trading on NYMEX and physical sales as represented by index. Industry struggles with an alternative to unreliable indexes but is still using index.

MMS Question: In the situation where one publication published 80 indexes then went down to 8 then 6, what would we have done?

Industry Comments:

- A company using gross proceeds would go back and renegotiate and still get paid on gross proceeds.
- We think this index issue is an anomaly, and shouldn't have a bearing.
- Free market works. Industry would work this out, if there is no fall back we would need solution, but don't think that's a problem.
- There is a disconnect between physical sales and NYMEX. Another problem is spread. If a party does a physical deal under NYMEX, they have to hedge. Ultimately that party is incurring a price risk that they have to manage. This is a consequence of value on a NYMEX-based transaction. There is a price risk that must be managed and there is a cost to managing that risk. The party will have to build that price risk into a bid, which will cost money. This is real and discoverable but not a physical sale.

MMS Question: What do we do in the interim?

Industry Comments:

- Talk to publishers. Each publisher assesses price differently and they have mechanisms to eliminate outliers or unreliable prices. They talked to buyers and sellers and anticipated that marketers would manipulate prices.
- Now, people still don't have confidence in index prices.
- The publishers have a problem giving details of how they calculate the index to us for first amendments reasons.

MMS Question: Is there anything wrong with the current rules, i.e. using affiliates' proceeds. Should we use netbacks? Do most companies have a system in place for internal purposes? Should we simply eliminate the benchmarks?

Industry Comments:

- Much would depend on the structure and organization of the marketing entity. If it is separate from producer, the producer does not always know what happens downstream. They only know what they get from the non-arm's-length sale. If the marketing entity is another department within the company, the producer can netback from the price the marketing department receives. It may be done, but is dependent on structure of company.
- If the downstream transaction price is based on index, price can be determined. If the downstream price is based on sales, the producer's value is based on what is passed back. The price influences how lessee will pay.
- In a contract between a producer and the marketing arm, if they share how they made money (pooling, aggregating) the price is reflective of index plus uplift, but sometimes marketer will make money and sometimes they will not.

State Comment:

- In New Mexico, all those companies can look through their affiliate's sales, not all companies everywhere can do this.

Industry Comments:

- We're surprised to hear that companies can trace back from the pool. There are different relationships between affiliates, not all relationships are the same. Any pass-through of value is very different throughout the industry.
- Does the affiliate definition present in the oil regulations apply to gas? Does MMS need to address this?

MMS Comment: The oil regulations reflect the National Mining Association court decision, our practice is to apply that decision to gas as well. The gas rule is written differently, but MMS is applying the concept the same way as we do for oil.

Industry Comments:

- Why would a company pay on index rather than gross proceeds, if gross proceeds were less than index? They are already doing a net back for other royalty owners. There are various types of systems, and tracing could be impossible.
- Once I make sale, I can't tell how to trace downstream, it may be impossible to determine how the molecules flow.

MMS Question: If we treat gas like oil, i.e. allow the option to use index as the basis for value, should it be on company basis? Or, should it be on an area basis? What are your thoughts?

Industry Comments:

- Hypothetically, producers might have scattered sales all over, but a marketing affiliate would have a limited area of sales.

MMS Comment: A producer affiliated with a marketer would not have traced through to the affiliate's sale but would have gone to the benchmarks to determine value. The benchmark might lead to index, but what if there were no index? Should we eliminate all references to gross proceeds and comparable contracts? Is index the correct answer if we have to go to the benchmark? Should we assume joint ventures look through their sales also?

Industry Comments:

- If an option is allowed, it should be inclusive or elective. If index is truly revenue neutral, then MMS shouldn't care if a company has different methods in different areas.
- If whatever pricing point is valid, an option should be available regardless of company corporate structure. If we went to index or gross proceeds and gross proceeds was impossible to determine, companies would have to use index.

State Comments:

- But is index revenue neutral? In our audits, we see that pricing is usually index plus or minus, so we don't think index is revenue neutral.
- If a company is selling, there is no need for marketing. The whole purpose of a marketer is to make money. In the end, the value is index plus.

Industry Comments:

- Marketing does not always result in uplift. A marketer is also buying and selling other production along way.
- If index is revenue neutral, it should be applicable to all companies regardless of structure. If it is available to some, it should be available to all on an area basis.

<u>Adjust Index for Location Differences</u>

Question: If everyone is comfortable using index, how do we adjust that index for location differences? From index to lease, if actual flow occurs, this can be calculated. What do you do if you have split stream and or don't flow, what location differential should be used?

State Comment:

- Why doesn't MMS market its own gas? Then, this is not an issue.

MMS Comment: We are marketing in kind offshore. However, our policy onshore is that unless a state is interested in RIK, then we won't do RIK. Wyoming does participate for oil, but other States don't have that same interest. If we do go to RIK in other states, we must develop regulations for taking in kind. Also, not all offshore is RIK.

Industry Comments:

- Markets work. By setting an arbitrary price it seems like MMS is trying to circumvent the market.
- This may not result in a fair value, but it results in simpler regulations.
- Does MMS post their RIK price?

MMS Comment: No, we do not.

<u>Allowable Transportation Costs</u>

Question: For situations where there is no physical flow, a suggestion from the Denver workshop was that MMS publish a rate based on previous reported transportation. This "postage stamp" rate for transportation would be fairly nominal, and companies could use this rate in lieu of calculating actual rates. Do you have any thoughts on this?

Industry Comments:
- We are very much in favor of simplifying. We would suggest exploring this concept. It gets rid of unnecessary calculations. A standard deduct helps companies and belongs on the screen to explore.
- This rate would be slightly less than actual costs, so it would not be a disincentive to just not calculate actual costs.
- Based on the comments in Denver, companies sometimes have to look back 12 months to recalculate, a standard rate would eliminate the cycle of a 12-month look back, reverse entry, and repay the transaction.

MMS Comment: If, for instance, production in the Powder River Basin is flowing east but the index is Opal (west flowing), there is no pricing point that is relevant to that east-flowing production. Opal is not applicable because the gas doesn't flow to that index. What should we do in that situation? Or, companies can have a sale where the producer is a party to a joint venture and can't control the sale. If we go to the benchmark and the benchmark yields index, what does the company use if there is no index, or if there are 4 indexes? Should MMS let the producer choose one index, should we require an average of indexes, should we require a volume-weighted average? Should MMS leave all discretion to lessee or should we specify everything? We are trying to decide if there is sufficient reason to change the rule at all.

Industry Comment:
- For a location differential in a no-flow situation, MMS should publish a postage stamp, or if there is another agency that exercises jurisdiction over transportation, MMS should consider their rules.

State Comment:
- Published rates are maximum rates, not discounted by actual negotiation. Should MMS allow companies to take that maximum rate, even if no one pays it?

Industry Comments:
- Published rates are a starting point, and should be considered.
- Companies are comfortable paying on what they receive. In a situation of index with split streams, we would not want a prescribed formula where rate is based on prescribed capacity. We would want the ability to approximate what might have been done. We don't want a mandated rate.

MMS Comment: Simply saying "use index price" won't solve the problem. If a company doesn't flow and uses the lowest index and the index is higher where they could flow, we would disagree with their choice of index. Is there a simple way to apply the valuation regulations and still get a fair value? In the Indian gas rule, transportation is based on 10% of index. Value is known, transportation is known, any thoughts on this?

Industry Comment:
- If this is applied just to an affiliate, would it still be the higher of?

MMS Comment: For every lessee in the index zone (arm's-length or non-arm's-length), transportation is 10%, not to exceed 30 cents, and not less than 10 cents.

Industry Comments:
- If this is applied to federal gas, it would depend on the percentage. Would it be across the board, or just for affiliate sales. If it applies just to an affiliate, 10% with some sideboards would work.
- This is a big issue on offshore. The offshore infrastructure is more costly. Transportation can be 50 and 75 cents on the same line. For instance, on Bluewater, some companies have 10 cent rates, some have 75 cent rates.

- Perhaps there could be different rates for deepwater. Is there some postage stamp rate?
- We don't like a floating rate. As prices skyrocket or drop, a stamp rate is not reflective of transportation.
- Our company is not willing to pay less than actual cost (which is too low). If we have an option of applying current rate against future postage stamp, we may choose to take future postage stamp to avoid an administrative rate, but we don't think the idea was that companies would accept a rate that is less than actual costs.
- Our company may want to pay on less that our actual costs. It may be worth it for MMS and industry to give up actual costs. There may be savings in simplicity, and we would give up on the revenue side to gain on simplicity side.

MMS Comment: Could we have a show of hands on changing the regulations? How many are in favor of continuing under the '88 regulations and affiliate resale? (2 States, one industry voted). How many think we need to change the regulations? (One industry voted). How many are not sure? (4 or 5 industry participants voted, others said it would depend on the changes made). Should we wait, based on market changes and with index in a state of flux?

State Comment:
- MMS should go to 1994-1997 committee report. The published minutes tried to figure out what are we discussing today. The proposed rule was very complex and wasn't fair to everyone. The conclusion was that the proposed rule would result in a revenue loss. If this is still the case, New Mexico would not be in favor of any changes. Any new rule must be revenue neutral.

Industry Comments:

- It may be good idea to publish that report. The report decided to stay with '88 rules after that 3 year (painful) process of negotiation.
- For now, MMS should leave the rules as is, but companies could come to MMS with an alternate proposal.
- Is there regulatory authority to do this on gas like we did on the oil?

<u>Allowable Transportation Costs</u>

Question: What transportation costs need clarification?

Industry Comments:
- For the oil workshop, we used the present gas regulations, as revised. We would like to revisit the list to see if there are other things to add, such as unused demand charges.
- In Denver, we discussed that industry uses different terminology. In the near future, the Royalty Task Force will define terminology as well as other areas or issues to consider. We identified one item on the oil side that is not allowed and relates to long term or aggregator sales and penalties. For gas intrahub transfer fees, industry sees this cost as a physical delivery between parties and believe it should be allowed. If you take into consideration that the cost is incurred whether someone sells at lease, and is allowed in RIK by MMS, then lessee should be allowed this cost.

MMS Comment: Does a lessee bear this cost if they sell at the lease and don't transfer title at market center? Is it a cost of transferring title? Sales are different than transportation and is this a sale cost, not a transportation cost? Is this a fee to change pipelines or title? Changes of title are not allowed in MMS opinion. Maybe this goes back to terminology, is it a cost a LDC would incur if they buy at lease? If the answer is yes, it may be allowable, if not, it is not a transportation cost and not allowable.

Industry Comments:

- If it's a cost the purchaser must bear, then it is considered in the value and must be allowable.
- It depends on flow from lease through hub to purchaser. If the gas is going to the hub, this cost will be incurred. A transporter does have to pay fee, regardless of whether a single entity holds title or multiple entities do, they will pay.

MMS Question: Are there other costs? Since the 1998 changes to the transportation regulations, are there new services that the pipeline is now charging? Are more pipelines making transporters put up letters of credit? We are looking at these kinds of new costs. Some inventory costs are charged in oil, but the gas market is different, are there these kinds of costs or others?

Industry Comment:

- We may want to send written comments on this, like the task force report, and States may have comments. COPAS planning to meet in May to discuss.

Lunch Break

<u>Allowable Rate of Return for Calculating Non-Arm's-Length Transportation Allowances</u>

MMS Comment: Some participants are not as familiar with the current regulations and aren't able to comment on the changes. Let us do a quick benchmark review.

- For gas sold arm's-length, the value is based on that arm's-length contract. If the sale is away from the lease, MMS allows transportation and processing deductions.
- If gas is sold non-arm's-length value is based on 3 benchmarks, applied in order
  - <u>1st Benchmark</u> Use the non-arm's-length price if equivalent to comparable arm's-length sales in the area
  - <u>2nd Benchmark</u> Use other relevant matters, including posted and spot prices, and a number of other factors
  - <u>3rd Benchmark</u> Use a net back, applied when lease product is converted, not usually invoked
- The distinction between arm's-length and non-arm's-length is defined as unaffiliated parties with opposing economic issues, based on a percent of control or ownership.
- The National Mining Association decision cites a presumption of control criteria.
- Opposing economic interest <u>and</u> control play a part.
- There are situations where the parties are not controlling, but also do not have opposing economic interests (joint venture). In this situation, MMS would test against the benchmarks, usually the 2nd benchmark.
- Because of 2nd benchmark complexity, we ask the question "Should we change the benchmarks?"
- To evaluate the "lessee's gross proceeds", MMS looks to the Texaco oil and Fina gas decisions.
- The decision on coal (the National Mining Association) will apply to oil and gas.
- A lessee with an arm's-length transportation contract can deduct the rate paid under its arm's-length transportation contract.
- For lessee-owned pipelines, lessee must base transportation on actual costs. The rate of return is the S&P BBB bond rate.
- Lessees with owned pipelines can get an exception to use a FERC- or State-regulated pipeline tariff.
- If there is no government-approved tariff, lessees must calculate actual costs.

Industry Comments:

- The gas rule understates the cost of capital, the oil and gas rules should track each other. This is one area where they could be the same. We could suggest options, reexamine assumptions, but we don't need to rethink this, it can be same as oil. The current administration is pro-production, no one is looking for a windfall, but we're not expecting a disincentive either.

State Comment:
- At the New Mexico workshop we discussed not having a rate of return at all. When a concession on National Park lands is granted, they aren't allowed to claim a rate of return. Why should this be done on government royalty leases?

Industry Comments:
- We are not asking for a rate of return, but there is a capital cost of investing money in a project. This is a difference in terminology.
- The deduction is for a recovery of the cost of capital, not a profit on investment. The BBB is well below industry norm for the cost of capital.
- What is the rate approved by FERC in rate filings?
- Between debt cost and equity, long term bonds and short term borrowing costs, a comparable risk is 12% for the equity portion, the debt portion is an actual cost of borrowing.

Question: Should MMS look into the actual cost of each company's debt rate and allow the rate of return to be different for each company rather than set at an across the board rate like the BBB bond rate?

Industry Comments:
- It should be the current BBB bond rate.
- We would expect anything we do here would also apply to processing and also to Indian gas. It should not be a different rate for all of these.
- We suggest the S&P Moody's for a rate for a pipeline company, perhaps on a yearly (12 month rate).
- Use a BBB proxy to represent overall company costs, both debt and equity, so MMS wouldn't have to get into FERC business.
- A possible alternative could easily be the S&P moody, but this captures only debt, not equity.
- Put a factor in a formula for equity
- Would MMS approve this rate?

MMS Comment: Any factor a company would choose would be subject to audit. If we use the BBB bond rate, this option offers the simplicity of being a known and not subject to audit.

Industry Comment:
- We should still use the BBB rate, but use a better multiplier based on industry average debt. This gives one number, not separate numbers, for every company. It should be higher than current rate multiplier (which is one).

MMS Question: In Denver, we discussed the problem with depreciable basis. Current rules dictate that if you acquire a pipeline, you use the remaining depreciable value. Companies say they would like to use what they paid to acquire the pipeline for as the depreciable base.

Industry Comment:
- It could be something less than the acquired basis.

State Comment:
- If the original owner sells for more than remaining depreciable value, how would the government recover the profit realized by the prior owner? There is a gain or capture that is never adjusted to the government's benefit.

MMS Comment: The basis issue was raised in Denver in addition to BBB rate issue. In both Denver and Albuquerque, it seems that the basis issue is bigger than BBB issue.

Industry Comment:
- In the oil rule, companies are able to claim a 10% minimum, we would want to see same in the gas rule.

Apply Index to Wellhead Volume

Question: If everyone agreed to use index, if a company paid on an index, should MMS allow that company to apply index to the wellhead volume in lieu of reporting gas as processed gas and liquids?

Industry Comments:
- We don't like this option if only transportation is deductible.
- What about an Operation Flow Order (OFO) situation where monthly processing is required?

MMS Comment: This is intended to get companies out of the business of reporting value under the processing reporting requirements and allows them to use a simpler method of reporting gas value based on MMBtu.

Industry Comment:
- Under an OFO, hydrocarbon dew point may be an issue and costs associated with this may be an allowable cost. (MMS asked the commenter to send us a description of this issue).

State Comment:
- If an affiliate is processing, why get out of following the value to the tailgate?

Industry Comments:
- Comments in the Denver workshop expressed concerned about the revenue neutrality of this option.
- Lately, there is no profit in processing liquids. If you are required to process and pay royalties on the price of liquids, you can end up losing on liquids.

MMS Comment: For a processing allowance you are only allowed to deduct costs against the value of the liquids, unless you get an extraordinary cost allowance. Under an OFO, does this cause a situation similar to a keepwhole contract, where you are back to full value?

Industry Comment:
- In the case of an OFO, all costs should be deductible. The company is forced to process even if it's not economical. We will send written comments on this.

State Comments:
- We're concerned about revenue neutrality. Is there a profit from processing? If this is allowed as an option for affiliates and if applied to arm's-length, too, is there a potential for loss of royalties?
- Don't want to allow lessee to pick and choose so they can manipulate. It should be an across the board option for a company so they do this for all situations, not just where it will benefit them.

Industry Comments:
- It is hard to say "yes or no" if we don't know what index is going to be, or how it will be applied. It's hard to comment on this.
- Processing is subject to audit, this option would simplify the audit process.

MMS Comment: Should this just apply in non-arm's-length situations. At previous workshops, others suggested that applying this to arm's-length situations would also simplify the process.

Industry Comments:
- Why make this a two-year option? You couldn't gain by switching month to month between affiliate and index.
- Why not one year rather than two?
- We don't understand such a long term commitment, gas markets change every month.
- We hear that industry would "game" the system, why would I take a loss on 7/8th of production to hurt 1/8th?

MMS Comment: Under this option, if you choose to process, you can choose to pay royalties as unprocessed gas using this MMBtu method. But, if you can choose a reporting option on a month-to-month basis to report using the MMBtu method when you are actually processing the gas every month, the principle reason you change reporting methods would be to pay less royalty.

State Comments:
- Under that scenario, it doesn't affect your monthly revenue, it is a royalty issue. You will pick the best way to maximize revenue, but pay royalties on whatever method would result in the least royalties.
- This is also a problem with keepwhole contracts, where you get best of both worlds.
- If this option is month-to-month, companies should have to compare the royalty reporting method to gross proceeds.
- MMS needs to clarify keepwhole reporting.
- This is dual accounting in a way. It would be different if you sell arm's-length, you don't compare unprocessed to processed gas in that situation.

Clarify Value under JOA Contracts

Question: Under the oil rule, when a non-operator elects not to take and sell its production under a joint operating agreement (JOA) and lets the operator sell for them, MMS would not regard that arrangement as a sale. The gas rule is silent on the issue of the JOA. Should we address? In the new oil rule, we included the JOA issue in the preamble, and the operator can elect to pay on index or gross proceeds. Do we need to clarify?

Industry Comment:
- In practice, is it an issue?

MMS Comment: Not so far. In the Denver workshop, one attorney stated that they've been advising clients for the past 5 years to execute true sales agreement instead of relying on the JOA.

State Comments:
- In New Mexico, it is an issue. MMS and DOJ have a dispute with company over its JOA.
- A JOA is not a sales contract. There is no sales price in that contract. Lessees must use the benchmarks to determine value.

Industry Comments:
- Under a JOA, it's a right not an obligation to sell gas. Small companies get into less advantageous situations when they sell gas, and will get a lower price. They may not be able to take gas themselves.
- If the affiliate's price is what the non-operator received, that is their gross proceeds.
- This assumes the non-operator will report royalties, this is not always true in a unit. The operator pays. This will cause numerous small entities to report, and the non-operator may not even be a company, but an individual.

MMS Comment: In the oil rule, if we have this situation, we assume that this is not a sale. Should we do same for gas? Or, as the current gas rule is silent, should we leave as is?

Industry Comments:
- This question is a concern to industry. If the operator is marketing to its affiliate, it's a non-issue as long as MMS doesn't question the non-operator transaction. It is a problem when MMS questions the non-operator's price because it is based on the price paid to the operator by its affiliate. A non-operator will not want liability when the operator sells to its affiliate. We are asking MMS to address this so the non-operator isn't liable. We're okay if MMS has no issue with non-operator getting the price between the affiliates.

State Comment:
- In an arm's-length sale, a lessee doesn't necessarily have to get the "best" price, but the government doesn't pay marketing. Say the price under the operator to affiliate sale is $1.00 less 2% marketing. We accept the $1.00, but not the 2% fee. Where is the obligation to market under non-operator transaction with the operator?

Industry Comment:
- The non-operator doesn't have the resources to sell, this assumes that non-operator <u>could</u> get a better price, but they can't, so the non-operator to operator sale is arm's-length.

State Comment:
- It isn't whether the non-operator gets a better price, but that we get gross proceeds, not net proceeds. The non-operator might be getting some price less the operator's marketing costs, which we feel is not correct.

Industry Comment:
- It's unfair to put the burden on the non-operator, grossly unfair.

MMS Question: Is this a form over substance issue? Is this a big issue, or has industry overcome this issue by executing separate sales contracts?

Industry Comments:
- This is not an issue, except we're concerned with the way MMS sees it.
- Actually, most of the group doesn't see that there are separate sales agreements being executed.

State Comment:
- This is a question of who bears what risk. Division orders and JOA agreements are not sales agreements and don't have language of who bears cost. The issue is more than form over substance, because there is a different purpose to the agreements, and there is a lot of protection under sales agreements that are not found under a JOA.

Industry Comments:
- There should be a presumption that the JOA is arm's-length, so to the extent that MMS does not see the JOA as an arm's-length contract, we do need to clarify. If we do that, will we require new reporting requirements and what would those requirements be?
- The operator will have to separate reporting for its arm's-length non-operators, and their own non-arm's-length affiliate sale.

State Comment:
- So there will be mixed reporting, one line for arm's-length, another line for non-arm's-length and reporters would follow the rules for each type of sale.

MMS Comment: If you are reporting, for yourself or for others, you are required to follow the arm's-length or non-arm's-length rules. This is required under the current rules.

Industry Comments:
- Relationships should not be forced on the non-operator, they should decide if it's arm's-length or non-arm's-length.
- Non-operator gets caught between a rock and hard place because the operator got nervous of the sales liability.
- Some companies have sold under this scenario for years and years, but it sounds like MMS would now require separate sales contracts.

MMS Comment: Under the Royalty Simplification and Fairness Act, you are only responsible for your share. MMS must know who is responsible and who to notify. This requirement was not necessarily chosen by MMS, but put on us by Congress and industry representatives.

MMS Question: There were a few other issues raised in other workshops. We had discussions on affiliate definition, unused firm demand, keepwhole contracts (not on costs, but more on reporting-why must companies reported keepwhole gas as processed). Should we make any other regulations changes?

State Comment:
- Either re-think why the keepwhole regulation exists or enforce the current regulations. If a company is not getting gallons reported to them, then they can't or don't follow the current rules.

No additional comments.

End of workshop.